Washington State Electricity System Study

Submitted to

Washington State Legislature

By

Washington Utilities and Transportation Commission
Washington Department of Community, Trade and Economic Development

In compliance with

Engrossed Substitute Senate Bill 6560

December 31, 1998

3. Strategies to Minimize Electric Service Costs

Strategies to minimize electric service costs are grouped in the same categories as trends affecting electric service costs: wholesale market, retail market, supply adequacy and reliability, environment, technology, and fuel cost. Stakeholder comments on the first draft of this report revealed a tension between maintaining desirable characteristics of the existing system and a desire to respond to changes in the market that may render existing policies and strategies ineffective. Discussion of strategies does not imply that any change is recommended or endorsed.

The wholesale market is not under state jurisdiction. However, actions taken within the state and region may help to minimize the cost of wholesale power. Potential strategies to minimize wholesale power costs include reinforcing the connection between Washington consumers and the benefits of the Federal Columbia River Power System (FCRPS) and promoting more effective wholesale competition through more efficient operation of the high-voltage transmission grid.

ESSB 6560 did not call for a comparison of alternative retail market structures, and the evidence concerning the effects of market structure on costs is inconclusive. Some strategies may help minimize costs in the presence of competitive pressure by: 1) reinforcing the connection between Washington customers and low-cost resources; 2) mitigating incentives to either shift or increase total costs; and 3) removing barriers to efficient market operation.

The likelihood of supply and capacity shortages in the Northwest in the winter is growing. These shortages may occur under adverse hydropower conditions, due to power demands that exceed the region's combined capability to generate and import power. The prospect of shortfalls is exacerbated by market uncertainty. Utilities may be increasingly reluctant to develop and execute plans to meet future loads reliably when those loads may be served by other power suppliers. Other resource developers may also face obstacles associated with uncertainty.

Potential strategies to reduce environmental costs of electric service are described in three categories: salmon recovery, global climate change, and aligning competitive markets with environmental objectives. "Internalizing" environmental costs in energy prices may decrease or increase total costs, depending on whether the value of the resulting environmental improvement exceeds the cost of the measures undertaken. Some strategies, including cost-effective energy efficiency, may reduce both economic costs and environmental costs of electric service.

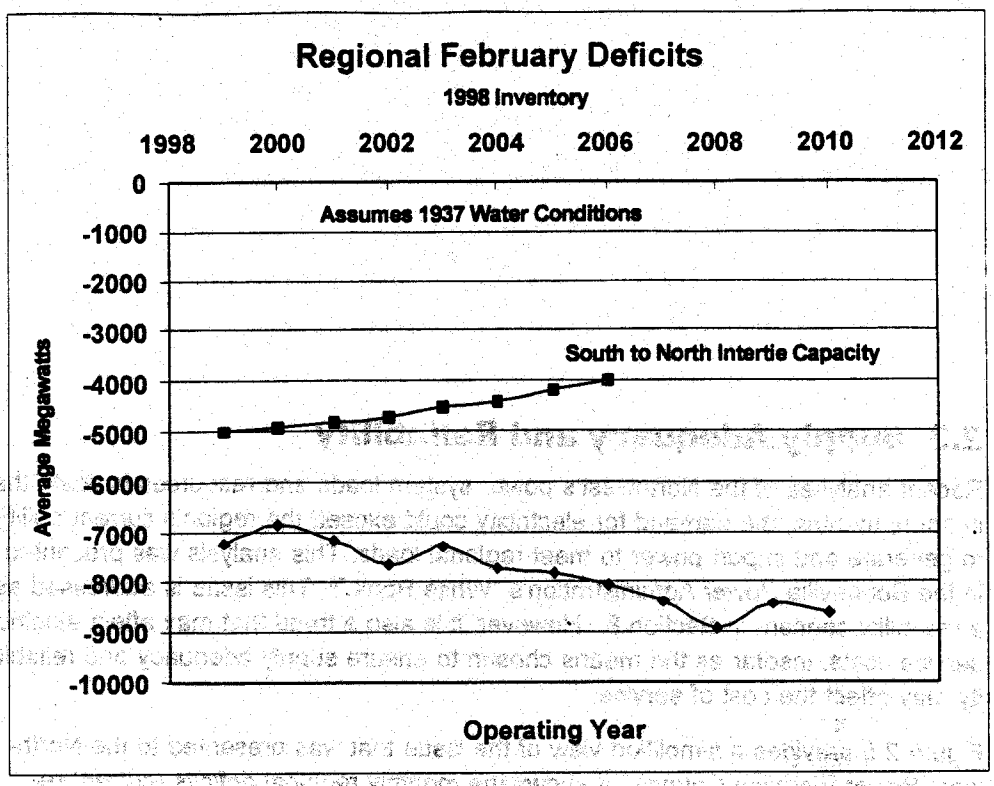
New and developing energy technologies hold significant promise for reducing electric service costs. Private firms, the federal Department of Energy, universities, national laboratories, and other research institutions are typically the leaders in energy technology development. However, the state can play a supporting role through policy initiatives and technology development partnerships. Periodic technology assessments may help to identify needs and opportunities.

2.3 Supply Adequacy and Reliability

Recent analyses of the Northwest's power system loads and resources indicate that in some months, the demand for electricity could exceed the region's current ability to generate and import power to meet regional loads. This analysis was presented in the Bonneville Power Administration's "White Book."[8] This issue is addressed as a reliability concern in Section 8. However, it is also a trend that may affect electric service costs, insofar as the means chosen to ensure supply adequacy and reliability may affect the cost of service.

Figure 2.5 provides a simplified view of the issue that was presented to the Northwest Power Planning Council. It shows the monthly regional deficits (current resources minus projected loads) that would occur in February with extremely adverse hydro conditions as represented by the conditions that existed in 1937. The bottom line depicts the region's power generation shortfall under such conditions. The top line depicts the approximate transfer capability of the North-South intertie, the main source of imported power. Its capability decreases with time as a result of load growth in the Northwest, which affects the ability to move power from south to north on the intertie. The growing gap between the two lines depicts the size of the deficits the region would experience under these very adverse water conditions. A similar but somewhat more severe problem exists when considering the ability to meet sustained peak loads. Those are the average loads during the peak ten hours per day for a five day work-week. During such a period, loads increase and generating capability may decrease due to extreme weather conditions.

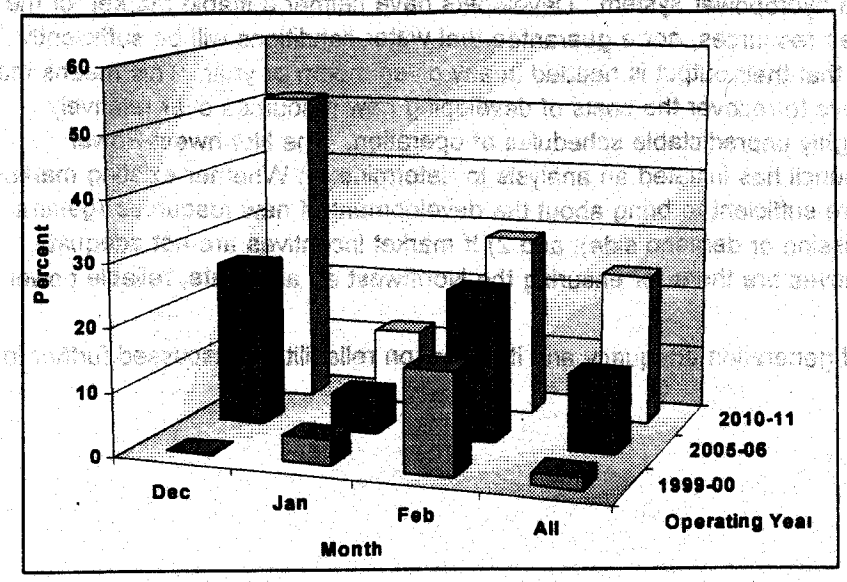
Figure 2.5 Regional February Deficits



The representation of the problem shown in Figure 2.5 is simplified in many respects. One of the most important is that it does not reflect the effects of year to year, month to month variations in hydro conditions. The Columbia River System cannot store the full annual runoff of the basin and the flexibility to use existing storage to maximize power production is increasingly limited. The difference in the hydro system's power capability from the driest to the wettest years is as much as 8000 average megawatts. These variations affect the probability that we will actually experience deficits in any given year.

To begin to assess the probabilities, Northwest Power Planning Council staff have looked at how frequently the regional deficit would exceed import capabilities in each of the winter months (December, January and February), based on the 50 water years in the historical record (1929-1978). This analysis was done for three different future operating years, assuming current regional resources and medium load growth. This is shown in Figure 2.6.

Figure 2.6 Probability of Monthly Energy Shortage



This figure indicates that for the 1999-2000 operating year, the likelihood of deficits in February is about 15 percent. By 2010-11, however, the likelihood of a deficit for December grows to roughly 50%. These deficits have been forecast for a few years now. But the magnitudes are increasing and the time available in which to take actions to avert a shortfall is becoming more limited.

In its preliminary look at this issue, the Northwest Power Planning Council reports that addressing these shortages is complicated by the changing nature of the utility industry. When utilities were less subject to competition, they acquired assets to provide an industry-standard level of reliability, including reserve generation and a robust transmission and distribution system. Regulators allowed investor-owned utilities to recover the cost of those assets in rates, even when some of those assets would be used very infrequently and cause increases in rates. With the prospect of competition, many utilities may be reluctant to include in their rates the cost of acquiring sufficient resources to serve loads that may have no obligation to remain on their system. To the extent that they are planning to meet future load growth, utilities increasingly rely on power purchases rather than constructing their own generation. Under the 1980 Regional Power Act, BPA has primary responsibility for meeting new regional loads when requested. However, many BPA customers no longer rely exclusively on BPA, and others question whether this is an appropriate role for a federal agency.

Additionally, a growing number of power suppliers are not regulated utilities but marketers or brokers who buy and sell power on the wholesale market without necessarily owning resources. Or they may be independent power producers without a captive customer base that assures them recovery of their fixed costs. Some utilities are selling off their generating assets. The result of these trends is increased risk for companies that acquire new generating resources.

This market risk may be compounded by the uncertainty associated with fluctuating output of the hydropower system. Developers have neither a stable market for the output of their resources, nor a guarantee that water conditions will be sufficiently unfavorable that their output is needed in any given month or year. This means that they may have to recover the costs of developing new resources over relatively short and highly unpredictable schedules of operation. The Northwest Power Planning Council has initiated an analysis to determine: 1) Whether existing market incentives are sufficient to bring about the development of new resources (generation, transmission or demand side); and 2) If market incentives are not adequate, what alternatives are there for ensuring the Northwest an adequate, reliable power supply?

The issue of generation adequacy and its affect on reliability is discussed further in Section 8.